BEFORE

THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2019-365-E

In the Matter of:	)
	)
Exploration of a South Carolina	)
Competitive Procurement Program as	)
Allowed by South Carolina Code	)
Section 58-41-20(E)(2)	)
	)
	)

DIRECT TESTIMONY OF STEVEN J. LEVITAS

ON BEHALF OF

THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE, INC.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Steven J. Levitas. My business address is 130 Roberts Street, Asheville, North Carolina 28801.

Q. WHAT IS YOUR OCCUPATION?

A. I am the Senior Vice President for Regulatory and Government Affairs at Pine Gate Renewables, LLC ("Pine Gate").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a B.A. from the University of North Carolina at Chapel Hill in 1976 and a J.D. with Honors from Harvard Law School in 1982. After clerking for a federal district court judge, I spent four and half years as a commercial litigator before becoming Director and Senior Attorney in the North Carolina office of the Environmental Defense Fund, a national public interest advocacy organization. In 1993, North Carolina Governor Jim Hunt appointed me to serve as Deputy Secretary of the North Carolina Department of Environment, Health, and Natural Resources.

Following my four-year tenure in that position, I spent the next twenty years as a partner in two private law firms where my practice was focused on environmental and energy matters. During the last six of those years, a particular emphasis of my practice was representing renewable energy companies, including the owners of "Qualifying Facilities" or "QFs" under the federal Public Utility Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C. §§ 824a-3, *et seq.*, in the negotiation of power purchase agreements ("PPAs") and renewable energy credit/certificate ("REC") purchase agreements with utilities, particularly with Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively, "Duke") in North and South Carolina. I continue to be employed by the law firm of Kilpatrick, Townsend & Stockton on a part-time basis as Senior Counsel.

In January of 2016, I became Vice President for Business Affairs and General Counsel for FLS Energy, Inc. ("FLS"), a North Carolina-based utility scale solar developer. At FLS, I was responsible for all legal, regulatory, and business development activities of the company, including the negotiation of a wide variety of contracts relating to our business. In January of 2017, following the acquisition of FLS by Cypress Creek Renewables, I was appointed to the position of Senior Vice President for Regulatory Affairs and Strategy at Cypress Creek, a position I held until joining Pine Gate in September of 2019 . In that capacity, I was responsible for and managed all aspects of policy, regulatory, and government affairs activity at Cypress Creek. That included extensive involvement in the development and passage of H.B. 589 in the 2017 session of the North Carolina legislative session, which created a new program of competitive procurement of renewable energy resources in Duke Energy's service territories "CPRE"). I was then also heavily involved in the preparation of comments on the North Carolina Utilities Commission's rules implementing the CPRE program which led to significant change and improvements to those rules, as well as in stakeholder processes relating to the requests for procurement under CPRE. While at Pine Gate I also worked on the 2019 South Carolina legislation that became Act 62 and was involved in the drafting of significant portion of the bill, including the sections on integrated resource planning and competitive procurement.

On October 23, 2018 and again on June 12, 2019, I made allowable ex parte presentations to this Commission concerning competitive procurement of generation resources. In addition, I was the principal author of a detailed proposal made by the Solar Energy Industries Association to the Federal Energy Regulatory Commission ("FERC"), and adopted in large part by FERC, to allow for the use of appropriately designed and implemented competitive solicitations as an alternative to traditional PURPA implementation.

Since joining Pine Gate I have continued to be an advocate of competitive procurement of electric generation resources and to be involved in competitive solicitation program design. In 2020, I co-chaired the Subcommittee on Competitive Solicitation of the North Carolina Energy Regulatory Process relating to the implementation of Governor Roy Cooper's Clean Energy Plan. My subcommittee produced a set of consensus policy recommendations relating to competitive procurement of generation resources. In addition, I am currently involved in the Michigan Public Service Commission's stakeholder process regarding competitive solicitation program design as well as similar negotiations between interested parties and DTE Energy. I was recently a continuing legal education faculty presenter on the subject of competitive solicitations in the electricity sector.

Q. WHAT IS PINE GATE RENEWABLES?

A. Pine Gate is a utility-scale solar development company headquartered in Asheville, North Carolina, with experience developing and building solar projects throughout the United States. We are currently developing projects in more than 15 states, but the Carolinas remain our largest and most important market. We currently have 43 projects in operation in the Carolinas totaling 470 megawatts ("MW") AC, 18 of which totaling 298 MW AC are in South Carolina. Our national development pipeline is over 10 gigawatts ("GW"), of which 3.2 GW are projects in the Carolinas, including 679 MW in South Carolina. Our past and currently planned investment in South Carolina is in excess of $900 million.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the South Carolina Solar Business Alliance ("SCSBA"), a Public Benefit Non-Profit Corporation, with its principal place of business at 1519 King Street Extension, Charleston, South Carolina 29405, for the purpose of promoting and advocating public policy positions supportive of solar power generation in South Carolina.[1]

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the benefits of competitive procurement of renewable (and other) energy generation resources and a variety of issues relating to competitive solicitation program design. In doing so, I will address, among other matters, the following issues on which the Commission requested testimony in its November 18, 2020, Directive Order (No. 2020-779):

(1) best practices;

(2) the benefits and monetary savings associated with establishing and administering competitive procurement programs for the utility and the ratepayer;

[1] The Carolinas Clean Energy Business Association ("CCEBA") filed a motion to be substituted for SCSBA in this docket on February 12, 2021. CCEBA is the successor to SCSBA in the representation of independent South Carolina solar developers in this and other regulatory proceedings before this Commission. No action has been taken on CCEBA's motion, and so this testimony is filed in SCSBA's name.

(3) the challenges and costs associated with establishing and administering competitive procurement programs for the utility and the ratepayer;

(4) the types of competitive procurement programs, or options available in competitive procurement programs for a utility, and the related benefits, savings, costs, and challenges;

(5) the impact of revisions to the utility's existing competitive procurement program; and

(6) the impact of addition of, or revisions to a utility's competitive procurement program upon other areas, including but not limited to the following: IRP process, interconnection, energy storage, and queue reform.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Exhibits SJL-1 through SJL-11.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. In Section II of my testimony I discuss the importance of the competitive procurement of generation resources, its many benefits to ratepayers compared to regulated monopolies, and several examples of the growing trend toward competition in generation procurement around the country, including measures short of structural reform that states can take to facilitate greater competition in the procurement of generation. In Section III, I discuss the process for identifying the resources that should be procured and express my opinion that, absent specific legislative direction with respect to resource procurement, this should generally be based on an integrated resource planning process. In Section IV, I discuss the important issue of participation by the utilities and their affiliates in competitive solicitations and express my view that the continued rate-basing of generation resources is an outmoded concept that presents unnecessary and undesirable risks for ratepayers. In Section V, I discuss a number of program design issues, including: (A) the importance of competitive solicitation programs being administered by independent third parties, especially where the utility and/or its affiliates are allowed to act as market participants; (B) the interconnection of competitively procured resources, including the treatment of system upgrade costs; (C) the importance of market information known to the utility being made available to other market participants; and (D) the utilization of form contracts approved in advance by the Commission. Finally, in Section VI, I provide detailed recommendations to the Commission regarding the approach to competitive solicitation of renewable and other generation resources. I recommend that the Commission adopt an approach similar to North Carolina's CPRE program in the near term, but consider migrating to an "all source" procurement program similar to that utilized in Colorado over the longer term.

Q. IN ACT 62, AS CODIFIED AT S.C. CODE ANN. § 58-41-20(E)(2), THE LEGISLATURE SPECIFICALLY DIRECTED THIS COMMISSION TO CONSIDER PROCEDURES FOR THE PROCUREMENT OF RENEWABLE GENERATION RESOURCES. ARE THE OPINIONS EXPRESSED IN YOUR TESTIMONY APPLICABLE ONLY TO PROCUREMENT OF RENEWABLES?

A. No. Absent a specific mandate from the legislature establishing a renewables procurement goal (similar to those enacted in North Carolina in 2017 and in Virginia in 2020), this Commission must first determine what type and quantity of resources should be procured before creating a competitive procurement program. However, the principles I discuss in my testimony are equally applicable to a renewables-only procurement or one that is open to multiple resource types.

II. THE IMPORTANCE OF COMPETITION

Q. WHY IS IT IMPORTANT TO PROMOTE COMPETITIVE PROCUREMENT OF ELECTRIC GENERATION RESOURCES?

A. The U.S. economy is founded on free markets and fair competition. Where suppliers must compete for market share, they are forced to find ways, through innovation and efficiency, to reduce the cost to customers of their goods and services or to make them more attractive through improvements in product quality and customer service. The one circumstance in which our economic system cannot provide these benefits of competition to the public is where natural monopolies exist – that is, where it does not make practical or economic sense to have multiple market participants. In these cases, it is essential that we have regulatory bodies like this Commission to set pricing and ensure that customers are protected from the abuse of monopoly power. But the regulation of monopolists is a challenging and imperfect undertaking, so regulated monopolies – a necessary evil in the case of true natural monopolies – should be the rare exception in our economic system, and free market competition should be promoted wherever possible. That is why over the past several decades we have seen a significant transition away from regulated monopoly structures to competitive markets in such sectors as the telecommunications and airline industries.

Q. IS THE ELECTRIC INDUSTRY A NATURAL MONOPOLY?

A. Only in some respects. In the electric industry, transmission and distribution services remain a natural monopoly. Since no one would want to see competing systems of wires crisscrossing the landscape, we need to maintain our current system of assigned service territories, with pricing regulated by state commissions and FERC. In contrast, electric *generation* is not a natural monopoly and there is no reason that we should allow monopoly utilities to be insulated from competitive pressure in providing generation services. Thirteen states and the District of Columbia have had deregulated retail generation markets for almost two decades, all of which are operating successfully today. As shown in Exhibit SJL-1, studies have shown that these markets have seen substantially better results for customers than states with regulated monopoly generation markets. More states would have almost certainly joined the wave of deregulation in the late 1990s and early 2000s had certain design flaws in the early programs and market practices – notably in California – not brought this trend to an abrupt halt.

Of equal or greater importance, dramatic changes at the wholesale level over the past several decades have created significant competitive pressure in generation markets. Specifically, as shown in Exhibit SJL-2, much of the country is served by organized wholesale markets in which regular auctions for energy and capacity together with open access transmission tariffs have created a liquid generation market based on competitive pricing. These markets are successfully meeting security and reliability requirements while delivering affordable, competitively priced electricity to consumers.[2] Here in South

[2] The recent crisis in the electricity sector in Texas appears to be due to a number of factors not relating generally to either wholesale or retail competition. First, uniquely in the country, Texas chose to isolate its power grid from the rest of the country, making it impossible to import power from other regions less affected by extreme weather. Second, unlike most other organized wholesale markets, the Electric Reliability Council of Texas ("ERCOT") elected not to establish a capacity market that would pay generators for committing to deliver power during defined time periods. Third, there is nothing that prevented ERCOT or the Texas legislature from mandating weatherization of electricity infrastructure as is done in many other places; those bodies made a bad bet that incurring such additional expense was not needed given the assumed lack of vulnerability to an extreme weather event of the sort that occurred.

Carolina, dozens of independent power producers with proven track records stand ready to provide low-cost, reliable power to South Carolina utilities.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS OF COMPETITIVE MARKETS VERSUS REGULATED MONOPOLIES?

A. Competitive markets have three primary benefits over regulated monopolies. The first and biggest is the same thing we see from competition across our economy: competition drives prices down and improves the quality of service for consumers, as multiple sellers must strive to innovate and achieve efficiencies (or accept lower returns) in order to acquire and maintain market share. As shown in Exhibit SJL-3, the increased market access that renewable generation has had over the last decade has helped drive prices down to the point that solar and wind are the cheapest sources of new energy on the market today.

Second, competitive markets insulate customers from the risks of utility-owned generation. In regulated generation markets, customers typically are made to bear the construction and operating risks associated with generating resources owned by the monopoly utility. South Carolina's V.C. Summer debacle is one of the more extreme examples of this risk to ratepayers. It is the rare occasion when regulated utilities are not allowed to recover from ratepayers most of the impact of construction delays and cost overruns. In addition, regulated investor-owned utilities ("IOUs") typically continue to recover generation plant costs regardless of their operating performance. In other words, IOUs privatize profits and socialize risks. By contrast, where energy and capacity are

---

Fourth, much of the crisis was due to the inability to pump and deliver natural gas, which has little to do with the design and regulation of the electricity sector. Finally, electricity infrastructure everywhere is vulnerable to extreme weather events, including here in the Carolinas, where we have seen significant outages due to hurricanes and ice storms.

provided by independent power producers ("IPPs"), they, not the ratepayers, bear all these risks. Specifically, IPPs get paid only for the energy they actually produce and deliver; if they fail to deliver, they lose revenue. That is not true for IOUs.

Finally, a huge benefit of a competitive market is that it gives customers choice as to the type of product they buy and the counterparty they deal with. The electric generation sector is one of the few in our economy where customers do not have this choice, though many very much want it. In particular, as shown in Exhibit SJL-4, a significant and growing number of private sector companies have committed to procuring renewable energy, in many cases having made 100% renewables commitments. Similarly, as shown in Exhibit SJL-5, polling data demonstrates a strong public preference for increased renewable energy deployment. In a regulated generation market like South Carolina's, these customers have very limited ability to meet these goals.[3] Since they must buy all their power from a single provider, their energy profile will necessarily be that of their generation supplier – which might look like 30% coal, 30% natural gas, 35% nuclear and 5% renewables. (Exhibit SJL-6 shows South Carolina's current generation mix, which on a pro rata basis is somewhat more heavily weighted towards nuclear.) It is critically important that mechanisms be in place that allow customers to meet their requirements and

[3] Pursuant to S.C. Code Ann. § 58-41-30, Duke's new GSA program and Dominion's new VRE program offer a limited number of customers the opportunity to procure green energy from the utilities.

preferences for 100% clean energy, or they will be discouraged from making further investments in the state.

Q. DOES THE PUBLIC UTILITY REGULATORY POLICIES ACT (PURPA) CREATE COMPETITIVE PRESSURE IN THE ELECTRIC GENERATION SECTOR?

A. Yes, to an extent. Because PURPA requires an electric utility to purchase the output of Qualifying Facilities ("QFs") at a price equal to the utility's marginal or "avoided" cost, the utility will, in effect, lose generation market share to QFs if it cannot reduce its costs below the level at which the QF can afford to produce. With the passage of the Energy Freedom Act in 2019, the South Carolina General Assembly expressed its clear intention to ensure that PURPA is implemented by this Commission and the state's investor-owned utilities in a way that facilitates competition from QFs. However, PURPA does not create an incentive for IPPs to drive their costs below the utility's avoided cost rate and does not replicate a truly competitive market in other respects.

Q. HAS THE SOUTH CAROLINA GENERAL ASSEMBLY SHOWN AN INTEREST IN OPENING THE SOUTH CAROLINA ELECTRIC SECTOR TO BROADER COMPETITIVE FORCES?

A. Yes. South Carolina Act 187 of 2020 established a legislative study committee (the Electricity Market Reform Measures Study Committee) to examine all forms of electricity market reform, including retail and wholesale competition. The study committee is expected to complete its work and deliver recommendations to the General Assembly by the end of this year. The General Assembly also included competitive solicitation elements in Act 62, including competitive procurement for major generating facilities (S.C. Code

Ann. § 58-33-110) and the authorization for this docket regarding competitive procurement of renewable energy (S.C. Code Ann. § 58-41-20(E)). The General Assembly has shown a strong interest in injecting more market competition into South Carolina's energy sector.

Q. SHORT OF THOSE MORE FUNDAMENTAL STRUCTURAL REFORMS, ARE THERE WAYS THAT THIS COMMISSION CAN REQUIRE GREATER COMPETITION IN THE PROCUREMENT OF ELECTRIC GENERATION?

A. Yes. As noted, this proceeding is the result of enabling legislation by the General Assembly that authorizes this Commission to consider whether and how to introduce greater competition in the procurement of renewable energy resources. In the context of a regulated monopoly regime such as that currently existing in South Carolina, there is a very straightforward way to do this: require regulated utilities to procure *all* new generation through a competitive process rather than seeking to meet identified generation needs by building new resources themselves.[4]

Q. IS THERE PRECEDENT FOR THIS APPROACH IN OTHER STATES?

A. Yes, there is a great deal of precedent. Here a are a few examples:

- In 2020, the Virginia legislature, with utility support, enacted the Virginia Clean Economy Act ("VCEA"), which requires the state's investor-owned utilities to propose

[4] Although the statute giving rise to this proceeding specifically authorizes the Commission to develop a program for the competitive procurement of renewable energy, I believe it has authority to extend such competitive procurement to all generation resources and that it is in the public interest for it to do so. As amended by Act 62, the Siting Act (S.C. Code Ann. § 58-33-110(8)(a) provides that a utility may not construct a generation facility with a capacity over 75 MW "without first having made a demonstration that the facility to be built has been compared to other generation options in terms of cost, reliability, and any other regulatory implications deemed legally or reasonably necessary for consideration by the commission." The commission is authorized to adopt rules for the evaluation of other generation options, and could reasonably require competitive procurement of such generation.

over 16 GW of solar generating capacity over the next 15 years.[5] While some of this supply is required to be procured from IPPs through power purchase agreements and some can be purchased from third-parties or developed by the utilities, all of it must be competitively procured. A summary of the VCEA competitive procurement requirements is included as Exhibit SJL-7 to my testimony.

- In 2017, the North Carolina General Assembly passed H.B. 589, which was specifically intended to migrate the state away from its traditional approach to PURPA implementation to a competitive procurement regime. In that case, the legislature directed Duke Energy to competitively procure more than 2,600 MW of new renewable resources and looked to future IRP processes to determine whether additional renewables procurement would be necessary and appropriate.[6] Through CPRE, Duke has now successfully contracted to procure more than 1,200 MW of new solar resources through this program at substantial cost-savings for customers. The Independent Administrator's recent filed report on Tranche 2 of CPRE is attached as Exhibit SJL-8 to my testimony.
- Colorado has been a national leader in the use of competitive solicitations for the procurement of new generation to replace expensive coal-fired power plants. A description of the successful Colorado competitive procurement program is set out in Exhibit SJL-9 to my testimony.

---

[5] Va. Code § 56-585.5 D.

[6] H.B. 589 provided that the 2,660 MW renewables procurement target would be reduced to the extent that Duke's legacy PURPA procurement exceeds 3,500 MW. *See* N.C.G.S. § 62-110.8. Because that threshold has been significantly exceeded, the total new procurement under H.B. 589 will be considerably less than 2,660 MW.

- In 2016 the Michigan legislature enacted a rigorous new IRP process under which the first IRP was filed by Consumers Energy. Consumers Energy's approved IRP accelerates coal plant retirements, calls for no new gas plant construction, increases the use of demand-side management and energy efficiency, and requires the competitive procurement of around 6 GW of new solar resources over the planning horizon. The Independent Administrator's report on Consumer's first round of competitive procurement is attached as Exhibit SJL-10 to my testimony.

III. DEFINING PROCUREMENT GOALS

Q. HOW SHOULD THE SIZE AND RESOURCE TYPE OF COMPETITIVE PROCUREMENTS BE DETERMINED?

A. There are two basic approaches to this question, and alternative options for both of them. The first approach is for a legislative body to mandate a defined amount and type of new procurement. As I mentioned, this is what was done in Virginia under the VCEA, where the legislature's specific goals were to accelerate coal plant retirement, limit new natural gas resources, and require major deployment of solar and wind. Similarly, as noted, H.B. 589 in North Carolina required a defined amount of new renewables procurement, driven not by environmental goals but by the correct belief that such procurement could save money for ratepayers. As a variation on this approach, a state legislature might mandate accelerated coal plant retirement and provide that resulting capacity needs are to be met by competitive procurement, without specifying the type of those replacement resources.

In contrast to this legislative approach, the second approach to defining competitive procurement goals is through the actions of a state utilities commission. Under such an approach, the state utilities commission determines through an integrated resource planning (IRP) process how much and what type of new generation should be procured. There are two ways that commissions such as this may approach that task. Under the first, which is what the South Carolina General Assembly has required in S.C. Code 58-37-40, investor-owned utilities must meticulously and empirically evaluate resource needs and propose a specific preferred resource portfolio for the commission to approve, modify or reject. That approved resource plan would then define the resources that the utility must competitively procure. Alternatively, under so-called "all source procurement," the IRP process does not initially produce a prescriptive plan with respect to resource type. Rather, the preferred resource portfolio is developed through a three-step process: First, the commission conducts a proceeding to consider the range of potential resource needs and a range of possible assumptions about key parameters, such as fuel costs and carbon pricing. Then the utility conducts a competitive solicitation to secure firm pricing for various projects that may be selected for the preferred portfolio. Finally, the utility proposes and the commission approves a preferred portfolio based on a determination of what is most prudent and reasonable in light of the bid prices, the risks presented to ratepayers, and any other applicable policy goals. In either case, the procurement may be, but is not necessarily, informed by legislative mandates regarding resource mix, such as a renewable energy portfolio standard or limitations on new fossil fuel sources.

Q. SHOULD ALL UTILITY GENERATION RESOURCES BE COMPETITIVELY PROCURED BASED ON NEEDS OR OBJECTIVES IDENTIFIED EITHER BY THE LEGISLATURE OR BY AN INTEGRATED RESOURCE PLANNING PROCESS?

A. My view is that a monopoly utility should generally not be allowed to build or procure a new generation resource for which it plans to obtain cost recovery unless two conditions have been met: First, the resource need has either been established by the legislature or determined by the regulatory commission through a rigorous, inclusive and transparent process. Second, the selected resource has been chosen through an inclusive, properly designed, fairly and independently administered competitive process that is open to all market participants. There could be rare and limited exceptions to this general principle, such as where a utility had a unique opportunity to acquire a generation resource at a discounted price, but these situations should be approached with caution.

Q. SHOULD THE PLANNING AND PROCUREMENT PROCESS CONSIDER DISPLACEMENT OF UNECONOMIC EXISTING RESOURCES AS WELL AS PROJECTED LOAD GROWTH?

A. Absolutely. Most of the resource additions in South Carolina over the next several decades will be driven by the replacement of increasingly uneconomic fossil-fuel plants. The planning process should routinely consider whether accelerated retirement or reduced utilization of existing resources has the potential to benefit ratepayers.

Q. ARE THERE OTHER FACTORS THAT AFFECT THE TIMING OF RESOURCE PROCUREMENT?

A. Given the lead time required to develop and build generation assets, it is important that the procurement process be started early enough so that the new resources can be available when needed. In addition, there may be some circumstances, such as the opportunity to take advantage of more favorable federal tax credits, in which it is in the interest of ratepayers to procure new resources sooner than would otherwise be the case. For resources that are being procured to reduce the energy or operating costs that would otherwise be passed along to customers, delays in the procurement process result in customers paying higher costs for longer than necessary.

Q. ARE REQUESTS FOR INFORMATION ("RFIs") OR REQUESTS FOR PROPOSALS ("RFPs") NEEDED FOR PRICE DISCOVERY IN ADVANCE OF THE IRP PROCESS?

A. Not under South Carolina's integrated resource planning process. S.C, Code Ann § 58-37-40 requires the utilities to perform and the Commission to consider detailed analysis of cost information for various resource types that is widely available in technical literature. As we have seen in the Dominion integrated resource plan proceeding, the Commission can evaluate this information and form a conclusion about the most prudent and reasonable generation portfolio for the utility. Moreover, after an initial cycle, there will have been post-IRP RFPs that provide price information for future cycles. However, I would note that under "all source" procurement, as implemented for example in Colorado, the RFP is integrated into the planning process as an intermediate step between the two phases of the commission's plan definition and approval.

Q. SHOULD THERE BE A COST CAP ON RFP BID PRICES, AND IF SO, HOW SHOULD IT BE ESTABLISHED?

A. A cost cap is only necessary or appropriate in some circumstances. If there is a definite need for new resources – either because of load growth, required retirements or contract expiration, or environmental mandates – then the procurement must occur regardless of price and the goal of competitive procurement is to ensure that the goal is achieved in the most prudent and reasonable manner possible. On the other hand, there are circumstances where the decision to procure may be dependent on the price at which procurement can occur. For example, if procurement is being driven by an assumption that new resources will save ratepayers money relative to the continued operation of existing resources, that assumption needs to be confirmed by the pricing obtained through the RFP. Similarly, if a specific resource type is selected based on assumptions about its cost, the actual pricing obtained needs to be consistent with those assumptions. Finally, if a commitment to decarbonization or renewable resources is contingent on their being procured at a price below a defined cap, as was the case with H.B. 589 in North Carolina, that requirement must be satisfied.

Q. CAN ENERGY STORAGE RESOURCES BE EFFICIENTLY INCLUDED IN A PROCUREMENT PROGRAM?

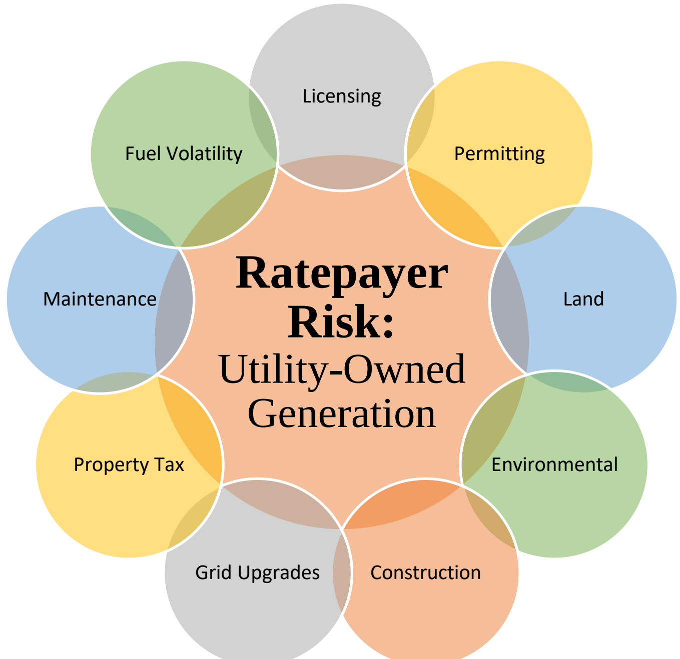
A. Yes. Storage coupled with renewables and stand-alone storage should be considered as resource options in the integrated resource plan. If they are selected in the preferred resource plan, they should be competitively procured like other resources. In the case of "all source" procurement, it would be necessary to establish in the first phase of the planning process what capacity and ancillary resource values should be attributed to storage resources.

IV. UTILITY PARTICIPATION

Q. SHOULD UTILITY OWNERSHIP OF NEW GENERATION RESOURCES WITH COST-OF-SERVICE RATEMAKING CONTINUE TO BE ALLOWED?

A. I should start by explaining the alternatives to utility rate-basing of generation assets. The most obvious one is for the utility to purchase power from an IPP pursuant to a contract for a term of years. Alternatively, as was done with CPRE in North Carolina, the utility can be allowed to act as a market-participant that competes and recovers costs just like an IPP (i.e., through defined production revenues and for a defined period of time). These alternatives are far better for ratepayers than traditional cost-of-service ratemaking (or “rate basing”). Rate-basing (i.e., allowing full recovery of the capital costs of an asset plus a defined return on equity) is an anomalous and outdated paradigm given that most generation is not a natural monopoly (except perhaps in the case of nuclear resources). As shown in Figure 1 below, rate-basing creates a variety of potential risks to ratepayers, including construction delays and cost overruns, operational underperformance and uncertainty about long-term market pricing. The procurement and cost recovery models I just described insulate ratepayers from all these risks.

Fig. 1: Ratepayer Risk from Utility-Owned Generation



Q. BUT ARE THERE BENEFITS TO RATEPAYERS THAT FLOW FROM UTILITY OWNERSHIP OF NEW GENERATION RESOURCES WITH COST-OF-SERVICE RATEMAKING?

A. It is important to distinguish between the issue of utility ownership and the issue of cost-recovery. As long as the resources are competitively procured in the first instance in an open and transparent process, there is no great harm to the utility ultimately purchasing and owning generation assets, as is allowed under CPRE. The problems I describe above are a function of allowing the utility to recover its costs through rate-basing. That said, utilities often make several arguments in favor of continued rate-basing of generation. In particular, they claim that the increased net revenues from their return on equity for rate-based assets fuels growth and attracts investors, thereby strengthening the financial health of the utility, which in turn benefits ratepayers. They also assert that having generation assets on their balance sheet strengthens their creditworthiness and reduces their cost of capital, which also has the potential to benefit ratepayers. However, to my knowledge none of these alleged benefits has ever been empirically quantified, nor has the level of utility ownership and rate-basing necessary to achieve them been demonstrated.

Q. DO YOU AGREE WITH THE UTILITIES REGARDING THESE POTENTIAL BENEFITS?

A. Without seeing any evidence to back these claims up, they seem highly speculative and uncertain. As I have said, the IOUs will continue to own and operate their transmission and distribution businesses the way they always have. Even where operation of the transmission system is placed in the hands of an independent system operator, T&D remains a healthy and sustainable business proposition for IOUs. Second, if the concerns raised by utilities prove to be demonstrated and quantifiable, they could be addressed through mechanisms other than utility ownership and rate-basing, such as an increased rate of return on other assets, a performance incentive mechanism, a financial compensation mechanism, or shared savings with ratepayers to the extent needed. Third, competition from IPPs should not create stranded assets for IOUs, who at a minimum should be able to recover the cost of prudent investments they have made in the past.[7]

Q. HOW WOULD YOU SUGGEST THAT THE COMMISSION CONSIDER THE POTENTIAL BENEFITS TO RATEPAYERS OF COMPETITIVE PROCUREMENT IN DETERMINING WHETHER AND TO WHAT EXTENT TO ALLOW CONTINUED RATE-BASING OF GENERATION ASSETS?

[7] Whether the utility should also be able to earn a rate of return on investments made in assets that are retired early for economic or policy reasons is a separate question.

A. While it would be preferable for such a decision to be made on the basis of empirical data, determining the size of any utility set aside needed to address the issues identified above in a manner that benefits ratepayers can be a difficult undertaking and, to my knowledge, has not been accomplished in other states. Rather, in states such as Virginia, Michigan, and Colorado, the amount allocated to utility ownership and rate-basing has been arbitrarily established through a process of political negotiation. However, I believe the starting point should be the principle that competitive pressures should be maximized, not minimized, to deliver rate savings to customers.

Q. ARE THERE ALSO OPERATIONAL CONCERNS THAT WEIGH IN FAVOR OF UTILITY OWNERSHIP AND RATE-BASING?

A. Utilities assert that their ownership of a significant portion of new generation is needed to ensure system reliability and flexibility and control in the operation of generation resources. As an initial matter, these concerns, if legitimate, would go to the issue of utility ownership or control, not cost-recovery through rate-basing. But substantively, I think they are red herrings. I'm not aware of any evidence that independently-owned renewable generation resources have inherently different performance characteristics or reliability profiles than comparable units owned by utilities. On the contrary, since independently-owned resources only get paid if they produce, they may actually have a greater incentive to perform reliably than utility-owned assets. On the second issue, a prominent statutory requirement of North Carolina's CPRE program is that the utility must have the ability to control and operate independently-owned generation resources just as it would its own.

Q. SHOULD UTILITY OWNERSHIP BE LIMITED TO, OR DIFFERENTIATED BY, RESOURCE TYPE?

A. There may be a case for greater utility ownership of resource types for which there is not a robust market of independent power producers, such as nuclear generation.

Q. IF UTILITY OWNERSHIP OF NEW GENERATION RESOURCES WITH COST-OF-SERVICE RATEMAKING IS ALLOWED, SHOULD SUCH RESOURCES BE PROCURED IN COMPETITION WITH THIRD-PARTY PPAS?

A. This is a complicated question. It is difficult to compare the cost utility-owned, rate-based assets, whose full cost plus an authorized rate of return is recovered over the useful life of the asset, to independently-owned assets that contract to sell energy and capacity for a defined term that is shorter than the facility's full useful life. In order to make such a comparison, a "terminal value" must be attributed to the independently owned asset for the remainder of its useful life after the initial contract period. That presents several problems. As an initial matter, it is far from certain that the IPP will even seek to sell its output to the utility after the initial contract period. Market opportunities for IPPs in twenty years may be dramatically different from what they are today. That aside, calculating the terminal value is a highly speculative and controversial proposition. One approach that has been used by DTE Energy in Michigan is to base the terminal value on a forecast of future energy prices. Where it is assumed that these will increase significantly, there is the potential to unfairly prejudice IPP bids if that assumption is inaccurate. In contrast, Colorado has based its terminal value on the average contract price over the initial term. A third option would be to fix the terminal value as the contract price in the final year of the PPA. None of these are perfect solutions.

Q. ARE THERE WAYS TO AVOID THE TERMINAL VALUE PROBLEM?

A. Yes, there are at least three options for doing so. First, the IPP could be allowed to contract for the same term as the IOU's cost recovery period. Second, the utility-owned and rate-based asset could be separately procured from the IPP/PPA assets, as is required in Virginia, which eliminates the comparison problem. And, of course, the simplest way to avoid the problem is not to allow utility rate-basing of generation assets at all and to require utilities to recover their costs in the same manner as IPPs, as has been done with CPRE.

Q. IF THERE IS TO BE A SET ASIDE FOR NEW UTILITY-OWNED, RATE-BASED GENERATION RESOURCES, HOW SHOULD SUCH RESOURCES BE PROCURED?

A. There is a compelling case to be made that, as in other states, such as Virginia, Michigan, and Colorado, such assets should be competitively procured through a "build-own transfer" model under which independent third parties convey assets to the utility at commercial operation (or potentially at notice to proceed and then contract with the utility for engineering, procurement and construction). There may also be tax benefits to the conveyance occurring some years after commercial operation.

Q. IF A SET ASIDE FOR UTILITY OWNERSHIP IS ESTABLISHED, SHOULD THE UTILITY AND/OR ITS AFFILIATES BE ALLOWED TO PARTICIPATE IN THE REMAINING (PPA) PORTION OF THE PROCUREMENT?

A. No. Other states have not typically allowed a utility that enjoys the benefits of a set aside to compete with third parties for the PPA portion of the procurement.

Q. IF UTILITY/AFFILIATE PARTICIPATION IS ALLOWED, SHOULD IT BE CAPPED AS IT IS UNDER DUKE'S CPRE PROGRAM?

A. Yes. Even with oversight of the procurement process by an independent third party, where the utility and/or its affiliates is allowed to act as a market participant in the competitive process (i.e., to compete for the right to sell to itself) there is the risk of self-dealing and the appearance of impropriety. That is addressed through a cap on the percentage of capacity that can be awarded to the utility in the competitive solicitation. CPRE's 30% cap seems appropriate to me. As discussed in the next section, independent administration of the solicitation process is key component to avoiding self-dealing and any appearance of impropriety.

V. <u>PROCUREMENT PROGRAM DESIGN</u>

A. Program Administration

Q. HOW DO YOU RECOMMEND THAT COMPETITIVE SOLICITATIONS BE ADMINISTERED?

A. That depends somewhat on whether the utility is allowed to compete as a market participant, as in CPRE. In that case, it is absolutely essential that the process be fully administered by an independent third party who designs and manages the procurement process, including development of the scoring methodology, and who scores the bids and selects the winning bidders. This is the established practice with CPRE in North Carolina and it has worked very well. Under this model there is likely to be a need for some utility involvement in the bid evaluation process, particularly with respect to the analysis of interconnection costs. Utility representatives involved in this process must be strictly insulated from their colleagues who are involved in the utility's market participation activities. This appears to have been handled very well under CPRE. Even where the utility and its affiliates are not participating in the competition, it is generally agreed that some level of oversight and involvement by an independent evaluator is important to ensure the integrity of the process and to prevent possible favoritism or the appearance of impropriety. This approach gives the utility more control over the process and the ability to flexibly consider more qualitative factors, which seems most appropriate when procuring utility owned assets.

Q. SHOULD PROVISIONS BE MADE FOR THE RESOLUTION OF DISPUTES?

A. That would be prudent. Ideally every procurement would run smoothly, with no disputes about the results of the procurement or its administration. But competitive solicitations are complex and the possibility for disputes always exists. Clear procedures for resolving disputes, both during a solicitation and after its conclusion, will help ensure the integrity of the process and minimize the possibility of disruptions.

B. Interconnection Issues

Q. HOW SHOULD THE STUDY OF INTERCONNECTION COSTS IN THE CONTEXT OF COMPETITIVE SOLICITATIONS BE HANDLED?

A. Market participants cannot be expected to provide final, binding bids without knowing the network upgrade costs associated with their projects. (Unlike network upgrade costs, interconnection facilities costs are sufficiently predictable that these can reasonably be estimated by market participants.) However, requiring bidders to have advanced through the interconnection study process to the point where they have received estimates of their network upgrade costs before their bid can be evaluated would have the effect of excluding many potential market participants, thereby increasing the average price at which awards are made. Measures should therefore be taken to accelerate the production of reliable network upgrade cost estimates. In the case of CPRE, this was done through an expedited preliminary study of the network upgrade costs for projects that were short-listed in the competitive solicitation.

Q. WHAT IS "QUEUE REFORM" AND HOW DOES IT RELATE TO COMPETITIVE SOLICITATIONS?

A. The Commission has approved major changes to the procedures governing Duke's study of interconnection requests, and Dominion is in the process of developing similar changes. These new procedures, generally referred to as "queue reform," replace sequential study of interconnection requests with the study of such requests in defined temporal and geographic clusters, with the cost of any required network upgrades being spread among participants in the affected cluster. These procedures will facilitate the study of the finalists and ultimate winners in a competitive solicitation being studied collectively. In addition, queue reform will have the effect of clearing out the large existing backlogs in the Duke and Dominion queues, making it easier to study competitive solicitation projects in a timely fashion.

Q. HOW SHOULD THE PAYMENT FOR NETWORK UPGRADES COSTS BE HANDLED?

A. Network upgrade costs should be attributed to project bids but should be paid for by the utility and recovered from ratepayers. Ratepayers will bear these costs whether they are assessed directly or factored into market participants' bid pricing (and should do so for any generation determined to be necessary and in the public interest, just as they do today). Requiring that upgrade costs be included in bids is problematic because the costs are often not known at the time of bid submittal, which could force bidders to increase their bid prices more than necessary. Conversely, if the bidder is held responsible for network upgrade costs not known at the time of bid submission, winning bidders may withdraw if they are not able to deliver on their bids because of larger-than-expected upgrade costs. To the extent that resource procurement is being conducted and evaluated pursuant to a cost cap, as is the case for CPRE, the estimated network upgrade costs will need to be evaluated alongside the project bids to ensure the total project costs are below the cost cap.

Q. HOW WOULD YOU RECOMMEND THAT VARIABLE INTEGRATION COSTS BE HANDLED IN THE CONTEXT OF COMPETITIVE SOLICITATIONS?

A. Any integration cost approved by the Commission should be factored in as a reduction to any cost cap established for the procurement. A similar approach has been approved by the North Carolina Utilities Commission in connection with CPRE. It is absolutely essential that bidders have certainty as to how integration costs will affect the cap on bid prices. In addition, as with CPRE Tranche 2, awardees should be paid a premium over their bid price if they able to mitigate integration costs in accordance with approved protocols.

C. Transparency

Q. WHAT SORT OF INFORMATION SHOULD UTILITIES BE REQUIRED TO PROVIDE TO MARKET PARTICIPANTS IN A COMPETITIVE SOLICITATION?

A. At a minimum, the utility should be required to provide information about the areas on its transmission system most likely to experience congestion and require network upgrades, and the most advantageous points of interconnection. This is especially important where the utility is allowed to compete as a market participant, so that the utility is not able to take advantage of inside information that no one else has access to. Also, where the utility is a market participant it should be required to share its forecasts and assumptions about market pricing after the initial procurement period.

D. Contract Documents

Q. SHOULD COMPETITIVE SOLICITATIONS BE CONDUCTED BASED ON NON-NEGOTIABLE FORM CONTRACT DOCUMENTS?

A. Yes. PPAs, Build-Own-Transfer Agreements, and Engineering, Procurement and Construction Agreements (which are applicable where ownership of the project transfers to the utility prior to construction) all contain many non-price terms that significantly affect the economics of the transaction and the value of the project to the utility and its ratepayers. These include performance security requirements, force majeure provisions and definitions, and cure rights for events of default. If these terms are subject to negotiation, the bid prices of market participants cannot be compared on an apples-to apples basis. In addition, contract negotiation has the potential to prolong and complicate the award process. Commercially reasonable form contracts can and should be approved by the Commission, just as they were by the North Carolina Utilities Commission for CPRE and by this Commission for PURPA transactions under Act 62. The Commission's approved PURPA PPAs provide an excellent starting point for competitive solicitation PPAs and do not require a lot of modifications to be used for that purpose. However, as I mentioned previously, one important change is that projects competitively procured by a utility should be fully dispatchable and curtailable, as opposed to PURPA QFs, which may only be curtailed in the case of narrowly defined "system emergencies." But those curtailment rights on the part of the utility cannot result in uncertainty for the seller with respect to contract revenues. Such uncertainty makes it difficult if not impossible for sellers to finance their projects – just as an investor-owned utility would not build infrastructure without significant certainty as to cost recovery. This issue can be addressed either by limiting uncompensated curtailment, as was done with CPRE or, as with utility cost recovery, by structuring PPA payments based on the capacity or potential output made available to the utility by the facility rather than the amount of output that the utility actually requires from the facility.

VI. RECOMMENDATIONS

Q. IN LIGHT OF THE FOREGOING, WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION REGARDING ITS APPROACH TO COMPETITIVE SOLICITATIONS FOR RENEWABLE AND OTHER GENERATION RESOURCES?

A. I respectfully offer the following recommendations to the Commission:

1. The Commission should direct each South Carolina investor owned utility to conduct a competitive solicitation for any new renewable energy resources identified as needed within the next five years in the preferred resource plan approved by the Commission in the utility's current IRP proceeding. Because of the higher federal investment tax credit that is currently available, such competitive solicitations should be initiated as soon as possible.

2. The utility and its affiliates should be allowed to participate in such competitive solicitations as market participants, subject to the following qualifications: (A) The cost recovery by the utility and its affiliates should be on a market basis so that they compete on a level playing field with third parties. That is, rather than being allowed to rate-base assets they own, the utility should be compensated based on

the product of its bid priced times its monthly output, just as third parties are under PPAs. (B) There should be a cap of 30% on awards made to utilities and their affiliates but no limit on the utility's ability to acquire third-party projects and to receive their PPA revenue streams.

3. The competitive solicitations should be conducted in accordance with guidelines adopted by the Commission that, among other things, provide for the competitive solicitation to be administered by an independent third party. Exhibit SJL-11 to this testimony is a proposed set of guidelines for the Commission's consideration that are based heavily on North Carolina's CPRE program. I address the following topics in the proposed guidelines: (A) the selection and role of an Independent Administrator; (B) communications between market participants; (C) the structure and process for conducting the competitive solicitation; and (D) form power purchase agreements for winning proposals.

4. With respect to non-renewable resources identified as needed within the next five years in the preferred resource plan approved by the Commission in the utility's current IRP proceeding, the utility should be allowed to own and rate-base such resources, provided that they are procured through a competitive process.

5. In the absence of a legislative mandate with respect to resource procurement, the Commission consider moving to a Colorado-style "all source" integrated resource planning and procurement model. I would encourage the Commission to open a docket to consider rulemaking for this purpose.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.